Arnold Schwarzenegger
Governor

OFFGASES PROJECT OIL-FIELD FLARE GAS ELECTRICITY SYSTEMS

PIER FINAL PROJECT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
California Oil Producers Electric Cooperative (COPE)

December 2008
CEC-500-2008-084

Prepared By:
California Oil Producers Electric Cooperative
Bob Fickes
Long Beach, California 90802
Commission Contract 500-02-016

Prepared For:
Public Interest Energy Research (PIER)
California Energy Commission

Paul Roggensack
Contract Manager

Pramod Kulkarni
Program Area Lead
Industrial, Agriculture and Water

Martha Krebs, Ph.D.
PIER Director

Thom Kelly, Ph.D.
Deputy Director
ENERGY RESEARCH & DEVELOPMENT DIVISION

Melissa Jones
Executive Director

Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

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- Renewable Energy Technologies
- Transportation

Offgases Project Oil-Field Flare Gas Electricity System is the final report for the OFFGASES Project (contract number 500-02-016) conducted by California Oil Producers Electric Cooperative. The information from this project contributes to PIER's Industrial/Agricultural/Water End-Use Energy Efficiency Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-4878.

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Abstract

Extracting oil in declining oilfields has become more difficult and expensive. About a third to one half of the cost of extracting oil from a well is the cost of energy expended to recover the oil. Most oil wells also generate gas of varying quantities. While some of the gas may be of quality suitable for pipelines, a significant portion of the gas cannot be delivered to a gas pipeline, as it is either too high or low in energy, too corrosive, too far from a pipeline, or too small a quantity to justify. This “stranded” gas often has nowhere to go and must be suppressed. A pressure bubble is created by the suppression and reduces oil production. Producers are forced to vent, flare, re-inject or incinerate the stranded gas resulting in energy waste, a step backwards from greenhouse gas reduction, and an increase in emissions. The Oil-Field Flare GAS Electricity Systems Project was conceived to find practical ways to consume stranded gas from oil wells in California. The project focused on four representative sources of oilfield stranded gas:

- High British thermal unit Gas
- Medium British thermal unit Gas
- Low British thermal unit Gas
- Harsh Gas

Keywords: Air quality permitting, building and safety permitting, combined heat and power (CHP), COPE California Oil Producers Electric Cooperative, DG distributed generation, electrical interconnection agreement, flare, harsh gas, high BTU gas, low BTU gas, microturbine, Oil-Field Flare GAS Electricity Systems, oil field flare, power export, self generation, standard offer tariff, stranded gas

Executive Summary

Introduction

Over the last several decades, oil production in California has steadily declined as existing oilfields have gradually become depleted. Between 1985 and 2005, the price of oil in California has ranged between $8.00 and $20.00 per barrel. Much of California's oil production was marginal at best and many wells that were capable of producing oil were shut down or in some cases abandoned because they were not economically viable to operate.

It was under these circumstances, before the recent oil price spike, that the California Oil Producer's Electric Cooperative began the "Oil-Field Flare GAS Electricity Systems" Project. California Oil Producer's Electric Cooperative members represent over 90 percent of the oil production in California. All oil-wells produce some gas in addition to the oil; some of this gas is pipeline quality and some of it is convertible into pipeline quality gas, but a large portion of the gas is unsuitable for pipelines. Due to the Southern California Gas Company Rule Number 30 regarding specifications[1] for pipeline quality gas, more gas has been stranded since it is no longer considered suitable for pipelines.

Purpose

The Oil-Field Flare GAS Electricity Systems Project demonstrated four separate solutions for waste gases:

- Medium British thermal unit Gas, 800-1300 British thermal unit
- High British thermal unit Gas, over 1600 British thermal unit
- Low British thermal unit Gas, below 350 British thermal unit
- Harsh Gas (with sulfur, nitrogen or CO_2 contaminants).

Project Objectives

The original objective of the Oil-Field Flare Gas Electricity Systems Project demonstrated how the four different types of waste gases could be converted to energy using microturbines. In addition, the project showed that gases whose properties were in between those tested could also be effectively used. Almost all oilfield stranded gas could be converted to useful energy.

The goal of the project was to select the best technology for each application; to evaluate how well the technology lived up to its expectations on reliability, emissions and costs; and whether the technology can be cost effective for the producer.

1. Quality specifications regarding heating value, moisture content or water content, hydrogen sulfide, mercaptan sulfur, total sulfur, carbon dioxide, oxygen, inerts, hydrocarbons, merchantability, hazardous substances, delivery temperature, interchangeability, liquids, landfill gas, and biogas.

Project Outcome

Medium British thermal unit: The first test site selected was a medium British thermal unit site located south of downtown Los Angeles. Gas from the site was previously sold to a local gas company. However, the gas did not consistently meet the Southern California Gas Company Rule Number 30 regarding specifications on natural gas quality and the gas company had to shut down the gas system every time gas quality didn't meet specifications. Each shutdown by the gas company disrupted the gas and oil flows.

The wells at this site were producing in several different production zones and the gas energy content at the site varied between 800 and 1400 British thermal units a cubic foot, depending on the well and the zone from which it was produced. The producers of this site agreed to treat its gas production so that it could be split into two types: one that met pipeline quality, and one that did not. The gas that did not meet pipeline quality would be used to power three microturbines.

Capstone microturbines were selected for this site. Due to the positive results of the project, the client has acquired nine more turbines and is planning to add them to their other sites.

High British thermal unit: The second test site selected was the high British thermal unit site in Signal Hill, California. The stranded gas at this site was rated at 1,763 British thermal unit a cubic foot. This project also used a Capstone microturbine that the client had already obtained. The field had been idle for several years without a solution for the stranded gas produced. After returning the wells to production, the gas flow declined substantially producing about 75 percent of the gas needed to run the microturbine. The first attempted solution was to run the turbine intermittently, however this was too hard on the equipment which is designed for continuous operation. After some experimentation, reprogramming, and adjustments the turbine was able to run continuously at a lower power output consuming all available gas and has been in near-continuous operation since. At this site, the turbine was responsible for returning three idled wells into service, and increased oil production by about 35 barrels per day. The client is considering microturbines at other sites to use the lower quality gas.

Harsh Gas: The site selected for harsh stranded gas was in the Maricopa area near Taft, California. At this site, the gas had high amounts of hydrogen sulfide, in the range of 5,000 to 6,000 parts per million and its energy content was low, about 500 to 700 British thermal unit per cubic foot. To meet air quality requirements, the sulfur had to be significantly reduced. Removing hydrogen sulfide on a large scale is widely practiced in refineries and elsewhere, but at a small scale operation it is difficult to find cost-effective hydrogen sulfide removal systems. An Ingersoll Rand microturbine was used to demonstrate another turbine technology. The project also uses waste heat from the turbine exhaust to heat the oil to assist with water removal and freed up additional gas that was previously used to generate the heat in boilers.

Low British thermal unit: As with high British thermal unit and harsh gas sites, there was much interest among California oil producer in hosting the low British thermal unit site. Several operators volunteered, and a site north of Ventura, California was selected. This site processes off-shore oil production; water is first stripped from the oil; then gas is stripped from the oil. The gas contains a high percentage of carbon dioxide, which must be removed to bring the gas to pipeline quality. The carbon dioxide contains residual hydrocarbons, mostly methane, and has a heating value of only 15 to 42 British thermal units a cubic foot. The carbon dioxide was processed through a thermal oxidizer where the residual methane and hydrocarbons were destroyed. The thermal oxidizer uses 200,000 cubic feet natural gas to destroy the hydrocarbons in the low British thermal unit gas.

The Flex-Microturbine, although not yet fully commercial technology, was the only feasible way to convert the low British thermal unit gas into electricity. Flex-Microturbines are designed to run on gas as low as 15 British thermal units per cubic foot or on stronger gas without a major retrofit. If Flex-Microturbines could replace the thermal oxidizer, 200,000 cubic feet a day of natural gas would be saved, a value of about $1,200 to $2,000 a day, or $400,000 to $700,000 a year. In addition, the site would generate 80 kilowatts of electricity for internal use or sale. Unfortunately, the project ran out of funds, and the low British thermal unit gas project was prematurely terminated.

Conclusions

Overall, this project was a technical success. The project demonstrated the ability of small oil producers to install, operate, and generate electricity using stranded gas as a free waste product fuel. There were many failed attempts prior to this project. Some of the oil producers participating in this project had previously attempted distributed generation on their own and had experienced a lot of frustration in obtaining the permits and approvals necessary from air management districts and local municipal districts. Obtaining proper tariff from local electrical utilities, finding good economical maintenance programs and solving noise mitigations problems were other unresolved challenges. This project met all these technical challenges and in many cases developed simplified tools to accomplish these tasks. All four participating companies are actively looking for ways to increase using distributed generation at their sites and other sites they operate.

Two of the four sites were successful economically. Restoring idle oil fields to production was successful, however additional work must be done to assure that all projects are economically feasible.

Recommendations

Two areas still requiring further work are the economic viability of the projects and further development of the ultra low British thermal unit turbine.

- Economics: Typically medium to small oil fields produce several times more stranded gas than they can consume at their oil fields. Today the utility can accept this extra electricity without compensation, but often will not. There are currently no tariffs that will allow the sale of power below one megawatt. Because this power is not considered "renewable" there is no incentive for the utility to take this power and pay for it, and no incentive for the oil operator to develop projects when there is an option to flare the gas.

There will be few distributed generation projects until standard offer contracts to purchase the excess power are available.

- Further development of the ultra low British thermal unit turbine: This project demonstrated that the Flex turbine was viable operating in difficult oil field conditions. Further development is needed to expand the reliability and to make the Flex turbine commercially viable.
- Consider changes to state policies to make producing clean and inexpensive energy economically viable for the oil field operators, and develop regulations that allow easy access to markets for the sale of power generated from stranded gas.

Benefits to California

Flaring is permitted by California's air managements boards, however if all flaring were converted to distributed generation, over 400 megawatts could be generated. Additionally the electric power generated by converting non-pipline quality stranded gas currently burned in boilers to combined heat and power could exceed 2,000 megawatts.

Since flaring and boilers typically emit much higher amounts of nitrogen oxides, and other greenhouse gases, changing to more environmentally friendly energy generating processes would contribute to reducing greenhouse gas emissions.

1.0 Introduction

This project addresses a significant problem in California. As California's oil production declines, it becomes increasingly more difficult to extract oil from oil-wells with less of the total fluids produced as oil and more of it as water. Oil production also includes some gas production. When such gas cannot be conveniently sent to gas pipelines, it becomes "stranded" from commercial markets and a problem for the producer. For most of California's oil production history, gas production, even when it is not stranded, has been considered a low value fuel. The gas must be disposed of in order to allow continued production of the higher value oil production.

In some instances, even pipeline quality gas cannot be sold because there are no natural gas pipelines nearby; similarly, many urban natural gas pipelines are shutdown because of encroaching urban renewal. This is especially challenging in the Los Angeles Basin with its recent proliferation of high rises through several existing oilfields. Gas that cannot be sold via natural gas pipelines must be suppressed, flared or vented. In the Los Angeles basin, venting is not acceptable because of the potential impact on nearby dwellings and businesses; even flaring is increasingly limited because of emissions limitations. If the gas is suppressed or re-injected into the well, it stymies oil production.

California has extremely rigid air emission standards for electrical generators. This electric power generation reduces emissions. The electricity generated from waste gas would offset the high cost of power otherwise purchased by the oil producer, shifting the economics significantly in favor of production. If successful, Oil-Field Flare GAS Electricity Systems (OFFGASES) would generate more power for California, reduce oil production costs, increase oil production and reduce emissions as well. At the national level, the benefits of increased oil production would reduce import needs. On a global scale, the OFFGASES project will reduce methane from vented gas, reduce Nitrogen Oxides (NO_X) from flares, and reduce carbon dioxide (CO_2) by offsetting generation elsewhere, helping meet the goals of the Greenhouse Gas Emission Standards, AB 32. Attachment I shows the rise of stranded gas in California in recent years.

This project seeks to find means to make electricity from the energy in stranded gas. The electricity may be used by the producer, or sold to the utility. If the gas that is currently being flared or vented were consumed in electrical generation, up to 400 Megawatts (MW) of electricity could be generated. This power would require no additional fuel, thus saving fossil fuel imports, and be better for the environment. With new technologies now available, an additional 2000 MW that could be generated from the gas behind shut-in wells or wells once considered uneconomic and by conversion of direct heat to Combined Heat and Power (CHP).

In order to cover as many types of stranded gas as possible, the project decided to focus on four separate streams of stranded gas commonly found in California. These streams are:

- Medium Btu gas, 800-1300 British thermal units (Btu)
- High Btu gas, over 1600 Btu

- Low Btu gas, below 350 Btu
- Harsh Gas (with sulfur, nitrogen or chlorine contaminants)

Almost all stranded gas falls into one or more of the above categories. The measure of technical success was to demonstrate that each of the four streams can be converted into electricity, or to show why not, and recommend alternate solutions.

The measure of economic success was measured from three points of view: the producer's perspective, the state's perspective and the national perspective. In addition, an assessment was made to recommend whether or not surplus power generated from stranded gas should be purchased by the utilities, and at what cost.

All sites selected were within the state of California, at either the Bakersfield or Los Angeles Basin oilfields. Many of these oilfields have been producing for over one hundred years, and production is generally in decline. If the cost of production from these wells can be reduced, and if an outlet can be found for stranded gas, oil production will increase in some cases and will continue longer in all cases.

The technologies to be considered for power generation include traditional technologies such as internal combustion engines, steam and gas turbines; they also include recently developed technologies such as fuel cells, microturbines and Stirling engines. The goal of the project was to select the best technology for each application, to evaluate how well the technology lives up to its expectations on reliability, emissions and costs, and whether the technology can be cost-effective for the producer.

Each of the sites was required to have appropriate building and safety, interconnection and air quality permits.

2.0 Project Approach

2.1 Project Goals

The goals of the project were:

- Demonstrate solid, repeatable, means to use stranded gas at oilfields for clean, electric power generation.
- Examine the economics of using stranded gas
- Find pathways to economic solutions
- Identify technology and regulatory bottlenecks and recommend means to remove them
- Transfer the technology lessons to oilfield operators and regulators

The first phase of the project was to meet with as many California oil producers as possible, present them the project goals and to seek their participation by providing suitable sites. This was done by preparing a presentation on the goals of the project, the methods to be used, and the anticipated results. California Oil Producers Electric Cooperative (COPE) initially conducted two seminars to disseminate the information: one in the Los Angeles area, and the other in Bakersfield. COPE members and non-member oil producers were invited, and over fifty people were in attendance at each of the seminars. Avid discussions took place, and 34 members and non-members provided details of their stranded gases. These details are included in Appendix C and provide a list of the companies that submitted proposed project sites and gas qualities submitted by seminar attendees.

From the information received, COPE and its partners evaluated the best potential sites for each of the four sub-projects. There were several candidates for each site, giving credence to the assumption that stranded gas is a major problem.

2.2 Project Plan: The Four Demonstration Sites

2.2.1. Medium Btu Site

The first site selected was the medium Btu site. Medium Btu was chosen for two reasons: it was the least challenging of all the sites, and it would provide a benchmark for the other sites.

The medium Btu site chosen was the St. James' Oilfield in Los Angeles, south of downtown, near the Staples Arena. Los Angeles has been a major oilfield for one hundred and fifty years. In most situations, as in St. James, down hole pumping is required to bring the oil to surface. St. James once had pipelines interconnecting to other oil wells in the area, where surplus gas or oil could be transferred back and forth to help meet specifications. However, with the building boom downtown, rights of way for oil pipelines have been revoked, and St. James must now operate independently.

The problem at St. James was that its gas did not meet the new Southern California Gas Company's Rule Number 30 regarding pipeline quality requirements. St. James total mix of gas was about 1250 Btu per cubic foot, while pipeline quality gas must be no more than 1150 Btu per cubic foot. The higher end hydrocarbons, such as C4s and C5s, had to be removed to meet quality requirements. The gas company required installation of a continuously monitoring gas chromatograph at the entry to its pipeline. When the chromatograph detected unacceptable gas quality, it shut down the gas which shut down the entire oil field. These shutdowns not only disrupted gas flow, they also disrupted oil flow. With no home for these high end hydrocarbons, St. James faced a dilemma, and was shut down for over three years prior to our project. To compound the problem, a gas pipeline to a nearby set of wells that could have provided relief by blending this gas with lower Btu gas was abandoned after construction of high-rise buildings in the vicinity appropriated the right-of-way.

An additional problem arose as a result of a steady flow of gas to the pipeline. The field is located in a very urban part of Los Angeles and at times, especially in the summer months when gas usage is low, there is not enough room in the pipeline for the total flow of gas from the oil field. The field then has to be shut in because there is once again no outlet for the gas production.

The solution proposed by COPE was to separate the high end fractions, thus meeting pipeline quality requirements for the bulk of the gas. The high end fractions would be used to generate electric power for use at the facility. This was by no means an easy solution because most power generating equipment also requires gas of stable, consistent quality. It was the sort of challenge that COPE wanted to resolve.

COPE met with the South Coast Air Quality Management District (AQMD) to make sure that air emissions from the site would be satisfactory. During discussions, it was learned that the AQMD had a few microturbines available for deployment in a manner to improve air quality. The AQMD agreed to provide COPE with three 30 kilowatts (kW) Capstone C30 microturbines that would be used for St. James.

This sub-project were comprised of:

- A gas refrigeration unit to separate the high end hydrocarbons
- A fuel compressor for all three units
- A moisture removal system to remove free water in the gas
- Three Capstone C30 microturbines
- Related controls, interconnections, electrical meters, gas meters, and other systems

The project went reasonably well. The microturbines were refurbished by the manufacturer. Manufacturer warranties were reestablished and the equipment was installed at the site. The gas stripper and moisture removal systems required several weeks of trouble-shooting before they functioned acceptably.

While noise from the C30s was within City of Los Angeles specifications, there were complaints from the neighbors. This was, after all, downtown Los Angeles. The C30s emit a high pitched sound, not unlike that of a jet engine. Several methods of sound-proofing were tried. Capstone recommended a sound absorbing shroud around the intake and back of the units. This eliminated some of the noise, however; noise complaints from the neighbors continued. We found a vendor that had an audio blanket that was designed to absorb the specific frequency of noise that the C30s emitted. This audio blanket was the final solution as the complaints from the neighbors' ended.

The St. James' system has now been in operation for over three years. The client is satisfied with performance. Since installation, shut-downs due to gas being out of specification have been reduced to a minimum. Oil production has resumed to 80 bbl per day. The client has obtained nine additional microturbines and plans to use them when the oil-field expansion plans are implemented.

The economics of the project are best summarized from the client's perspective. Prior to the project, the client was not able to deliver gas, and thus also not able to produce oil. Since the project, the client is producing and selling natural gas, producing oil, and also generating 80 kW of electricity for internal use. The payback on investment is significant.

Appendix A includes drawings providing details of the site.

Appendix B includes site and installation photographs.

2.2.2. High Btu Site

The selected high Btu site was the Termo oilfield in Long Beach north of Signal Hill. This oilfield has been tapped for well over a hundred years, and continues to produce.

At Termo, the gas concentration was over 1,700 Btu a cubic foot, with a large fraction of C4s and C5s. This gas could not be put into a pipeline. The client had installed a separator to add the high ends to the oil, thus sweetening the oil, but the remaining gas was still too rich for the pipeline and remained stranded.

A microturbine was installed by the client at his other oil operations, but had not run well and was shut down most of its time. The site had been experiencing problems related to design changes to the on-site compressor, and was prone to gas production and Btu fluctuations.

After some consideration, it was decided that the best solution at Termo was to tune the microturbine in such a manner that it would be able to handle the fluctuating gas flow rate. These changes would make the machine a fuel-follower, using all the fuel gas available at any time, thereby resolving the problem of fluctuating fuel supply.

The solution has worked well. The system now operates around the clock, and has shown an availability of over 85% over the last three years.

Appendix B includes pictures of the installation.

The client is happy with the resolution of the problem. Thanks to the microturbine consuming all gas at site, oil production has increased from 0 to 35 bbl per day. The client is planning to install additional microturbines at his other oilfields, using the solution developed by the OFFGASES Project to consume the gas.

The economics of the project are best summarized here by the client's perspective; the value of the power generated was small compared to the increase in oil production and the accompanying confidence in future production. The savings amounted to $19,000 a year from power and $1,000,000 a year from increased oil revenues.

2.2.3. Harsh Gas Site

There were several candidate sites for harsh gas that is stranded. Of these, the site selected was the Maricopa site belonging to Drill-Pro, a small oil company. Maricopa is located 80 miles north of Los Angeles, and about 30 miles east of Bakersfield, California. The site has several oil wells, with no gas pipeline nearby so all gas was being flared. The challenge was that the gas had high sulfur content, in the range of 5,000 to 6,000 ppm of sulfur in the form of Hydrogen Sulfide (H_2S). The high sulfur content is hard and corrosive on the generating equipment and created air emissions that did not meet air management standards and made the gas difficult to use for power generation.

Several solutions were considered for removal of the sulfur. The problem was that most sulfur removal processes are intended to process high volumes of gas flow, and cannot be economically scaled down to the size needed for this project. The research effort was to find the best sulfur removal system for this site.

The SulfaTreat process is a chemical reaction that removes the hydrogen sulfide from a gas stream via specially designed reactant products. The apparatus consists of a fixed-bed or batch-type granular hydrogen sulfide reactant contained in a pressure vessel. During the process, sour gas or vapor flows through the granular SulfaTreat product in the bed, where the hydrogen sulfide reacts with the reactant to form a stable and safe by-product. The system is tolerant of variations in gas flow and content. From time to time the bed must be replaced. The project achieved this without major shutdowns by having two beds, one primarily for removal and the second for polishing. When the first bed is spent, flow is diverted to the second bed while the first bed is replenished and brought back on line as a polisher.

The medium and high Btu sites both used Capstone Turbines. In order to test a different system, an Ingersoll Rand 70 kW (IR70) turbine was chosen for this location. The system has two separate turbines, one for the generator and the other for the air compressor. Unlike the Capstone, the IR70 is a fixed speed machine, running with a gear-box and a traditional synchronous generator.

The SulfaTreat system was consuming significantly more reactant than anticipated, and had to be replenished much more frequently, an unplanned expense. With careful tuning, the quantity of reactant used has been reduced, and it is hoped that it can be reduced further.

One problem unique to this site was that the client did not have adequate local load to consume the power generated by the IR70. Compounding this problem, as a fixed speed machine, the IR70 does not perform as well at partial loads, and the manufacturer did not want the system operated below 90% load. While gas was available to run the machine at high power, if there was no load on site, the power would have to be exported to the utility. The client was willing to give away the power to the utility at no charge.

This seemingly simple fix turned out to be a challenge. Pacific Gas and Electric (PG&E) was not initially willing to accept the "free" electricity. It required a study, and then required the addition of a ground-bank and other devices as a condition for allowing a limited amount of power into its system. During periods of low demand, the power delivered to the grid would sometimes exceed the limit. The utility would shut down the generating system every time the power delivery reached the limit. These shutdowns triggered a demand charge and a stand-by charge for the electricity needed by the client to replace the lost power. The stand-by and demand rates were so high that any savings generated from power production were more than offset by the costs. The client installed a bank of electrical heaters, just to dissipate surplus electricity to avoid stand-by and demand charges.

This project is not yet cost-effective and by far the least from showing an economic success of the four projects. The high costs of sulfur treatment and the high cost of generating surplus power are the key factors that make the project uneconomical.

There are many oilfield sites that face this dilemma. Many sites that have stranded gas do not have sufficient electrical demand to consume all power generated. If utilities do not buy the power, this vital fuel is wasted, increasing NO_X and hydrocarbon emissions, when it could be used to generate power.

The client has the potential to generate at least another 500 kW at this site, but unless a reasonable price is available for the electricity generated, will continue to flare the gas.

Appendix C shows gas quality, Appendix B shows pictures of the installation.

2.2.4. Low Btu Site

As with the other sites, there were several candidates for the low Btu gas. The site selected was the DCOR Rincon facility. At Rincon, oil from several offshore oil rigs is brought ashore. The water is stripped from the oil, after which gas is stripped. The gas contains high amounts of carbon dioxide. The carbon dioxide is removed from the gas using an amine plant, and the flow of CO_2 is about 500,000 cubic feet a day. The problem is that the CO_2 contains small amounts of hydrocarbons, and the facility has to destroy the hydrocarbons before the gas is vented into the atmosphere.

The tail gas contains hydrocarbons expressed as between 1.5% and 4% methane. In order to destroy these hydrocarbons, the tail gas was being processed through a thermal oxidizer that consumes 200,000 cubic feet of natural gas a day providing the heat to destroy the hydrocarbons.

The project therefore undertook to find a way to use the hydrocarbons in the tail gas for power generation. There were two potential solutions:

- Concentrate the hydrocarbons to the extent that they could be used in a conventional power plant.
- Look for a power plant that could run on 1.5% to 4% methane in a gas stream.

Technologies for concentrating the methane were expensive, and the energy used in the process would probably be greater than the energy recovered. It was therefore decided to look for a power plant that could handle the low Btu gas. The only system available was FlexEnergy's Flex-Microturbine that runs on 1.5% methane or higher. Even though the technology was not yet commercial, it held sufficient promise that it was decided to use it.

A 30 kW Flex-Microturbine was installed at the site. It was started up with high Btu natural gas and then weaned over to low Btu gas. The system operated reasonably well for periods, but it was discovered that the "quality" of the low Btu gas was not consistent. Emissions from the Flex-Microturbine are well below 1 ppm, the lowest of any current power plant.

The system operated reasonably well even though there were a couple of start-up related failures due to a bad compressor wheel and an overheated catalyst. Unfortunately, the project ran out of funds, and the endurance testing could not be completed.

The Flex-Microturbine has drawn a lot of interest with oilfield operators. An interesting feature is that even though it was chosen for the low Btu site, the same system could have been used for medium or high Btu. The Flex-Microturbine accepts gas at atmospheric pressure, and then dilutes it with air to the desired 15 Btu/scf threshold. This means that all fuels no matter what their initial strength can be used in a Flex-turbine, giving the opportunity for the one-size-fits-all solution that oilfields prefer.

Appendix A shows site drawings.

Appendix B shows installation pictures of the Flex-Microturbine at the Rincon site.

3.0 Project Outcomes

3.1 Economic Issues

3.1.1. Medium Btu

The medium Btu site had a significant payback potential because both oil and gas were being suppressed as a result of tight gas quality requirements. All 90 kW of power generated by the microturbines could be used on site and there was no need to export power. When a solution was found that allowed both gas and oil production to increase, and with a big increase in oil prices, the project proved to be economically sound. The total project cost was $497,000, providing a payback of 2.5 months. The $497,000 resulted in an oil production increase of 80 barrels a day, and gas production of $950 a day; the benefit is about $2,700,000 a year. The value of the power generated, while helpful, was a minor cost relative to the overall savings. The client is considering adding several more microturbines.

3.1.2. High Btu

At this site, too, stranded gas had eliminated oil production for over three years. A microturbine installed by the client at his other facilities had not been successful. The client decided to try and install the microturbine at his Long Beach facility and solicited the help of the OFFGASES team. From our experience at the Medium Btu site a resolution of the technical issues was found and oil production was reestablished initially at 15 barrels a day, and eventually increased to 35-40 barrels per day. Project cost was $397,000; benefits are $1,000,000 a year, with a payback of 4.5 months. This client is considering installing microturbines at its other sites.

3.1.3. Harsh Gas

The economics of this project were more complex. In order to use the harsh gas, it was necessary to remove sulfur from the gas. The sulfa-treat system operation costs, which were largely the cost of chemicals consumed, is averaging $325 a day; there was no immediate benefit from oil production because the client was already able to flare the gas. The project had to stand on the value of power generated. The site power requirements were less than the power generated by the turbine, but the utility would neither accept nor pay for surplus power generated. The utility finally relented and accepted a small amount of surplus power without payment. Even so, whenever the power exceeded the limit, the utility would shut down the power plant. The shutdowns meant that the client had to buy additional, high priced power from the utility, and incur high standby charges. The higher pricing negated all savings to the client from power generation. The client then installed a resistance heater bank, dissipating the surplus electricity just to keep the utility from shutting down the system.

Between the cost of sulfur removal and the limited opportunity to generate power, the economics of this project did not materialize. The unable situation resulted in a waste of electric power, and unnecessary emissions. A change in tariff that requires utilities to purchase all power from stranded gas would eliminate this problem.

The project cost was $262,000, the annual savings at this time are only $22,000, with a payback of 11.8 years. Should the proposed stranded gas tariff be implemented, the annual savings will be between $45,000 and $63,000, making a significant difference. If the stranded gas tariff is implemented, the site owner plans to put in an additional 250 kW generator, which would generate between $203,000 and $286,000. This would reduce the amount of flaring to emergency use only and would consume nearly all of the stranded gas.

3.1.4. Low Btu

The economics of the low Btu site were compelling. The site "destroyed" 500,000 cubic feet of 15 to 45 Btu gas a day in its thermal oxidizer. The oxidizer consumed 200,000 cubic feet of natural gas a day, at a cost of $1,500 a day. If the low Btu gas could have been used to generate power, the fuel savings would be about $500,000 a year, a major difference compared to the value of the power generated, which was only $30,000 a year. The project had spent about $329,000 when funds ran out. During this time, a Flex-Microturbine was installed and operating. Had the project been completed as planned, the project payback period would have been less than one year.

Unfortunately, circumstances changed during the project. The client had a CHP system that provided heat for oil operations, but in 2007 the turbine combustor was destroyed in a fire. The thermal oxidizer became the only source for heat at the site. It is now fired with about 400,000 cubic feet a day, and now there is no fuel benefit to destroying the low Btu gas in a turbine. The client is now looking at alternate means to generate power with its surplus gas.

3.2 Regulatory, Electrical Tariff and Public Policy Issues

The largest impediment to the success of these "stranded gas to electricity" projects is still in the regulatory, electrical tariff and public policy areas. These issues hamper the smaller independent oil operators much more than the larger oil operations. Large oil production operations have more options to deal with stranded gas than just distributed generation. The smaller operations often have more stranded gas generating capacity than they have electrical load to consume, and today export of that power is not an option for the following reasons:

- **Regulatory.** There is a strong market of electrical purchasers wanting to purchase electric energy that is produced in an environmentally friendly way. Some businesses and households are willing to spend a premium if the electrical power is produced in a way that helps the environment. Compared to traditional renewable power sources, (wind, solar, biomass and landfill), stranded gas generation is much cheaper to produce. Because it is not classified as renewable under current regulations, it is nearly impossible to sell power from stranded gas projects. Regulators need to work with utilities and industry to develop regulations that allow recognition and easy access to markets for the sale of this power.

- **Electrical Tariff.** The PURPA act of 1978 Requires that all "QF" qualified projects be offered a Standard Offer contract to sell power to the utilities at "SRAC" prices. It is up to each state to set the formula from Short Run Avoidance Cost (SRAC). The SRAC formula in California has needed modification for nearly a decade. There has been a ongoing dispute between the electrical utilities and industry over this formula. The California Public Utilities Commission, which approves contracts between utilities and industry, has discouraged new standard offer contracts until the SRAC issues have been resolved, therefore only renewal of existing standard offer contracts have been attempted during this time period. The California Independent System Operator (CAISO) Schedules the power to the electrical grid. It has a minimum of 1,000 kW, or 1MW from any generating location. The addition of the potential 200 MW to 2,000 MW from stranded gas generation would be a great asset to the CAISO. However, development of this additional generation would require the CAISO to drop its minimum threshold down to 100 kW, thereby allowing smaller DG projects to participate.

- **Public Policy.** Power produced from stranded gas reduces air emissions from flaring, venting of natural gas, and boiler steam generators through CHP; however these projects currently receive no credit or recognition reducing greenhouse emissions. California has a requirement for renewable energy to be the source of at least 20% of the total electricity sold by in the state. The state's retail sellers of electricity are generally a long way from complying with this requirement. As required by state law, the Public Utilities Commission annually develops a set of Market Price Referents (MPR) to compare against power supply contracts using renewable energy sources. The MPR is the cost of electricity ($/kWhr) below which renewable energy source power supply contracts will not require above market payments. Electricity produced from stranded gas does not qualify as renewable under state law, but can provide a low-cost, environmentally beneficial source of power. However, electricity from stranded gas receives no clear benefit from public policy mechanisms and therefore no benefit or recognition is given to those who develop the projects and no benefit or recognition is given to those who purchase the power from these projects. Public policy should in some way support all forms of environmentally friendly generation.

4.0 Conclusions and Recommendations

The OFFGASES project showed that all oilfield stranded gas can be used to generate electric power. Whether stranded because it is high Btu, low Btu, harsh gas, or simply because it cannot be conveniently delivered to a pipeline, the gas can be utilized. In many cases, the cost of generating the electricity may be offset by gains in oil production. In other cases, the cost of power generation may be offset by reduced purchase of electricity. For oilfields that do not have a high electricity demand, there are currently no outlets available to sell the electricity. This constraint results in waste of an important fuel, for the gas is otherwise vented, flared or re-injected, and results in reduced oil production. It also results in increased emissions, because flares generally produce significantly more NO_x than distributed generation power plants.

The problem with stranded gas would be significantly smaller if utilities were required to purchase all power from stranded gas at reasonable rates, allowing oil producers to develop projects that would reduce emissions, increase oil production, help towards energy self-sufficiency, reduce greenhouse gas emissions, and create jobs.

5.0 Technology Transfer Program

The Technology Transfer program has been a big success. The IOGCC has already published several articles in trade journals and industry publications touting the success of the project. It has also developed a brochure on the OFFGASES Project. Attachment II includes copies of these publications.

COPE has presented the OFFGASES Project at two annual meetings of the IOGCC.

Several meetings during the course of the project were held at the Petroleum Technology Transfer Committee (PTTC) where the major topic of discussion was the OFFGASES Project.

Copies of these meetings and seminars can be found in Appendix D.

Already several oilfield operators are looking for solutions such as those developed by the OFFGASES Project. Technology Transfer was successful.

6.0 Glossary

AQMD	Air Quality Management District
BTU	British Thermal Units
CAISO	California Independent System Operator
CARB	California Air Resources Board
CEC	California Energy Commission
CHP	Combined heat and power
CO_2	Carbon dioxide
COPE	California Oil Producers Electric Cooperative
CPUC	California Public Utilities Commission
DG	Distributed Generation Technology
DOE	U. S. Department of Energy
H_2S	Hydrogen Sulfide
IOGCC	Interstate Oil and Gas Compact Commission
IR	Ingersoll Rand
kW	Kilowatt or thousand watts
LADWP	Los Angeles Department of Water and Power
mcf	thousand cubic feet
MW	Megawatt or million watts
NETL	National Energy Technology Laboratory
OFFGASES	Oilfield Flare Gas Electricity Systems
PAC	Project Advisory Committee
PG&E	Pacific Gas & Electric
PIER	Public Interest Energy Research
PUMP	Preferred Upstream Management Practices
PURPA	Public Utilities Regulatory Policy Act
QF	Qualifying Facility (under PURPA guidelines)
R&D	Research and Development

SCAQMD	Southern California Air Quality Management District
SCE	Southern California Edison
SRAC	Short Run Avoidance Cost (cost of utility to turn on additional electrical generation. This cost is used to set the price of power from QF projects)
scf	Standard cubic feet